Exh. SJK-1T

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

DOCKET NO. UE-17____________

DIRECT TESTIMONY OF

SCOTT J. KINNEY

REPRESENTING AVISTA CORPORATION

I. INTRODUCTION

Q. Please state your name, employer and business address.

A. My name is Scott J. Kinney. I am employed as the Director of Power Supply at Avista Corporation, located at 1411 East Mission Avenue, Spokane, Washington.

Q. Would you briefly describe your educational and professional background?

A. Yes. I graduated from Gonzaga University in 1991 with a B.S. in Electrical Engineering and I am a licensed Professional Engineer in the State of Washington. I joined the Company in 1999 after spending eight years with the Bonneville Power Administration. I have held several different positions at Avista in the Transmission Department, beginning as a Senior Transmission Planning Engineer. In 2002, I moved to the System Operations Department as a Supervisor and Support Engineer. In 2004, I was appointed as the Chief Engineer, System Operations and as the Director of Transmission Operations in June 2008. I became the Director of Power Supply in January 2013, where my primary responsibilities involve management and oversight of short- and long-term planning and acquisition of power resources.

Q. What is the scope of your testimony in this proceeding?

A. My testimony provides an overview of Avista's resource planning and power supply operations. This includes summaries of the Company's generation resources, the current and future load and resource position, and future resource plans. As part of an overview of the Company's risk management policy, I will provide an overview of the Company's hedging practices. I will address hydroelectric and thermal project upgrades, followed by an update on recent developments regarding hydro licensing.

A table of contents for my testimony is as follows:

Q. Are you sponsoring any exhibits?

A. Yes. Exh. SJK-2 includes Avista's 2015 Electric Integrated Resource Plan and Appendices, Confidential Exh. SJK-3C includes Avista's Energy Resources Risk Policy, and Exh. SJK-4 includes the Generation and Environmental Capital Project Business Cases.

II. RESOURCE PLANNING AND POWER OPERATIONS

Q. Would you please provide an overview of Avista's owned-generating resources?

A. Yes. Avista's owned generating resource portfolio includes a mix of hydroelectric generation projects, base-load coal and base-load natural gas-fired thermal generation facilities, waste wood-fired generation, and natural gas-fired peaking generation. Avista-owned generation facilities have a total capability of 1,925 MW, which includes 56% hydroelectric and 44% thermal resources.

Table Nos. 1 and 2 summarize the present net capability of Avista's hydroelectric and thermal generation resources:

Table No. 1: Avista-Owned Hydroelectric Generation

Project Name	River System	Nameplate Capacity (MW)	Maximum Capability (MW)	Expected Energy (aMW)
Monroe Street	Spokane	14.8	15.0	11.2
Post Falls	Spokane	14.8	18.0	9.4
Nine Mile	Spokane	36.0	32	15.7
Little Falls	Spokane	32.0	35.2	22.6
Long Lake	Spokane	81.6	89.0	56.0
Upper Falls	Spokane	10.0	10.2	7.3
Cabinet Gorge	Clark Fork	265.2	270.5	123.6
Noxon Rapids	Clark Fork	518.0	610.0	195.6
Total Hydroelectric		**972.4**	**1,079.9**	**441.4**

Table No. 2: Avista-Owned Thermal Generation

Project Name	Fuel Type	Start Date	Winter Maximum Capacity (MW)	Summer Maximum Capacity (MW)	Nameplate Capacity (MW)
Colstrip 3 (15%)	Coal	1984	111.0	111.0	123.5
Colstrip 4 (15%)	Coal	1986	111.0	111.0	123.5
Rathdrum	Gas	1995	176.0	130.0	166.5
Northeast	Gas	1978	66.0	42.0	61.2
Boulder Park	Gas	2002	24.6	24.6	24.6
Coyote Springs 2	Gas	2003	312.0	277.0	287.3
Kettle Falls	Wood	1983	47.0	47.0	50.7
Kettle Falls CT	Gas	2002	11.0	8.0	7.5
Total			**858.6**	**750.6**	**844.8**

Q. Would you please provide a brief overview of Avista's major generation contracts?

A. Yes. Avista's contracted-for generation resource portfolio consists of Mid-Columbia hydroelectric, PURPA, a tolling agreement for a natural gas-fired combined cycle generator, and a contract with a wind generation facility.

The Company currently has long-term contractual rights for resources owned and operated by the Public Utility Districts of Chelan, Douglas and Grant counties. Table No. 3 provides the estimated energy and capacity associated with the Mid-Columbia hydroelectric contracts. Additional details on these contracts are presented in Company witness Mr. Johnson's testimony.

Table No. 3: Mid-Columbia Hydroelectric Capacity and Energy Contracts

Counter Party – Hydroelectric Project	Share (%)	Start Date	End Date	Estimated On-Peak Capability (MW)	Annual Energy (aMW)
Grant PUD – Priest Rapids	3.7	12/2001	12/2052	36	19.5
Grant PUD – Wanapum	3.7	12/2001	12/2052	39	18.7
Chelan PUD – Rocky Reach	5.0	1/2015	12/2020	56	33.0
Chelan PUD – Rock Island	5.0	1/2015	12/2020	25	17.0
Douglas PUD - Wells	3.3	2/1965	8/2018	24	17.4
Douglas PUD – Wells renewal	2.0	9/2018	9/2028	14	8.1
Canadian Entitlement[1]					**-3**
20175 Total Net Contracted Capacity and Energy				**180**	**102.6**

Table No. 4 below provides details about other resource contracts. Avista has a long-term power purchase agreement (PPA) in place through 2026 entitling the Company to dispatch, purchase fuel for, and receive the power output from, the Lancaster natural gas-fired combined-cycle combustion turbine project located in Rathdrum, Idaho. In 2011, the Company executed a 30-year power purchase agreement to purchase the output (105 MW peak) and all environmental attributes from the Palouse Wind, LLC wind generation project that began commercial operation in December 2012. Mr. Johnson provides details related to the remaining contract rights and obligations in Table No. 4.

Table No. 4: Other Contractual Rights and Obligations

Contract	Type	Fuel Source	End Date	Winter Capacity (MW)	Summer Capacity (MW)	Annual Energy (aMW)
Energy America, LLC[2]	Sale	Various	12/2019	-50	-50	-50
Douglas Settlement	Purchase	Hydro	9/2018	2	2	3
WNP-3	Purchase	System	6/2019	82	0	42
Lancaster	Purchase	Gas	10/2026	290	249	222
Palouse Wind	Purchase	Wind	12/2042	0	0	40
Nichols Pumping	Sale	System	10/2018	-6.8	-6.8	-6.8
PURPA Contracts	Purchase	Varies	Varies	47.6	47.6	28.8
Total				**214.8**	**91.8**	**279**

Q. Would you please provide a summary of Avista's power supply operations and acquisition of new resources?

A. Yes. Avista uses a combination of owned and contracted-for resources to serve its load requirements. The Power Supply Department is responsible for dispatch decisions related to those resources for which the Company has dispatch rights. The Department monitors and routinely studies capacity and energy resource needs. Short- and medium-term wholesale transactions are used to economically balance resources with load requirements. The Integrated Resource Plan (IRP) generally guides longer-term resource decisions such as the acquisition of new generation resources, upgrades to existing resources, demand-side management (DSM), and long-term contract purchases. Resource acquisitions typically include a Request for Proposals (RFP) and/or other market due diligence processes.

Q. Please summarize Avista's load and resource position.

[1] Energy America, LLC sale is 50 aMW through 2018 and then decreases to 20 aMW in 2019.

A. Avista's 2015 IRP shows forecasted annual energy deficits beginning in 2026, and annual capacity deficits beginning in 2021. These capacity and energy load/resource positions are shown on pages 6-9 through 6-12 of Exh. SJK-2, and are also provided in Avista's 2015 IRP load and resource projection.

The 2017 Electric IRP is currently being developed and is scheduled to be filed with the Commission on August 31, 2017. Besides ongoing energy efficiency programs, the new resource needs are expected to be later than those identified in the 2015 IRP because of updates to the load forecast and the amount of currently secured resources.

Q. How does Avista plan to meet future energy and capacity needs?

A. The 2015 Preferred Resource Strategy (PRS) guides the Company's resource acquisitions. The current PRS is described in the 2015 Electric IRP, which is attached as Exh. SJK-2. The IRP provides details about future resource needs, specific resource costs, resource-operating characteristics, and the scenarios used for evaluating the mix of resources for the PRS. The Commission acknowledged the 2015 Electric IRP in Docket No. UE-143214 on March 14, 2016. The IRP represents the preferred plan at a point in time; however, Avista continuously evaluates different resource options to meet current and future load obligations. The Company held the first meeting of the Technical Advisory Committee on June 2, 2016 to begin the 2017 IRP effort and will conclude with the sixth meeting on June 20, 2017.

Avista's 2015 PRS includes 193 MWs of cumulative energy efficiency, 41 MWs of upgrades to existing thermal plants, and 525 MWs of natural gas-fired plants (239 MWs of simple cycle combustion turbines (SCCT) and 286 MWs of combined-cycle combustion turbine (CCCT)). The timing and type of these resources as published in the 2015 IRP is provided in Table No. 5.

Table No. 5: 2015 Electric IRP Preferred Resource Strategy

Resource Type	By the End of	ISO Conditions	Winter Peak	Energy
Natural Gas Peaker	2020	96	102	89
Thermal Upgrades	2021-2025	38	38	35
Combined Cycle CT	2026	286	306	265
Natural Gas Peaker	2027	96	102	89
Thermal Upgrades	2033	3	3	3
Natural Gas Peaker	2034	47	47	43
Total		565	597	524
Efficiency Improvements	**Acquisition Range**		**Winter Peak Reduction (MW)**	**Energy (aMW)**
Energy Efficiency	2016-2035		193	132
Distribution Efficiencies			<1	<1
Total Efficiency			193	132

Q. Would you please provide a high-level summary of Avista's risk management program for energy resources?

A. Yes. Avista Utilities uses several techniques to manage the risks associated with serving load and managing Company-owned and controlled resources. The Energy Resources Risk Policy, which is attached as Confidential Exh. SJK-3C, provides general guidance to manage the Company's energy risk exposure relating to electric power and natural gas resources over the long-term (more than 41 months), the short-term (monthly and quarterly periods up to approximately 41 months), and the immediate term (present month).

The Energy Resources Risk Policy is not a specific procurement plan for buying or selling power or natural gas at any particular time, but is a guideline used by management when making procurement decisions for electric power and natural gas as fuel for generation. The policy considers several factors, including the variability associated with loads, hydroelectric generation, planned outages, and electric power and natural gas prices in the decision-making process.

Avista aims to develop or acquire long-term energy resources based on the current IRP's PRS, while taking advantage of competitive opportunities to satisfy electric resource supply needs in the long-term period. Electric power and natural gas fuel transactions in the immediate term are driven by a combination of factors that incorporate both economics and operations, including near-term market conditions (price and liquidity), generation economics, project license requirements, load and generation variability, reliability considerations, and other near-term operational factors.

For the short-term timeframe, the Company's Energy Resources Risk Policy guides its approach to hedging financially open forward positions. A financially open forward period position may be the result of either a short position situation, for which the Company has not yet purchased the fixed-price fuel to generate, or alternatively has not purchased fixed-price electric power from the market, to meet projected average load for the forward period. Or it may be a long position, for which Avista has generation above its expected average load needs, and has not yet made a fixed-price sale of that surplus to the market in order to balance resources and loads.

The Company employs an Electric Hedging Plan to guide power supply position management in the short-term period. The Risk Policy Electric Hedging Plan is essentially a price diversification approach employing a layering strategy for forward purchases and sales of either natural gas fuel for generation or electric power in order to approach a generally balanced financial position against expected load as forward periods draw nearer.

III. GENERATION CAPITAL PROJECTS

Q. Please explain how the Company prepared its case with regard to generation capital projects.

A. In this proceeding the Company is proposing a Three-Year Rate Plan from May 1, 2018 – April 30, 2021. For Rate Year 1 (effective May 1, 2018), the Company started with the historical test period ending December 31, 2016. The Company then reviewed the planned capital projects for 2017 and determined a threshold for pro forma capital projects consistent with the development of a Modified Historical Test Period Study (Traditional Pro Forma Study). The Company has identified Generation projects that are equal to or greater than one-half of one percent of the Company's rate base - i.e. above $6.9 million. Those projects have been included in the Traditional Pro Forma Study.

The remaining planned capital projects for 2017 are included within the Company's 2017 End of Period (EOP) Study, which is the basis of the Company's request for rate relief in this proceeding. The EOP Study, therefore, reflects the capital projects included in the requested revenue requirement for Rate Year 1 (May 1, 2018 – April 30, 2019).

In my testimony, I have also explained the capital additions going into service during Rate Years 2 and 3 of the Three-Year Rate Plan (includes capital projects from 2018 through April 2021) as a part of Company witness Ms. Andrews' "Rate Year Study." For further discussion regarding the Traditional Pro Forma Study, the 2017 End of Period Study, and the Rate Year Study, please see the testimony of Company witnesses Ms. Schuh and Ms. Andrews.

Q. Company witness Mr. Morris identifies and briefly explains the six "Investment Drivers" or classifications of Avista's infrastructure projects and

programs. How then do these "drivers" translate to the capital expenditures that are occurring in the Company's generation area?

A. The Company's six Investment Drivers are briefly described as follows:

1. Customer Requested - Respond to customer requests for new service or service enhancements;

2. Customer Service Quality and Reliability - Meet our customers' expectations for quality and reliability of service;

3. Mandatory and Compliance - Meet regulatory and other mandatory obligations;

4. Performance and Capacity - Address system performance and capacity issues;

5. Asset Condition - Replace infrastructure at the end of its useful life based on asset condition; and

6. Failed Plant and Operations - Replace equipment that is damaged or fails, and support field operations.

The main drivers for the generation-related capital investment include:

- Updating and replacing century-old equipment in many of the Company's hydro facilities to reduce equipment failure forced outages;
- Regular responsive maintenance for reliability to keep generating plants operational;
- Projects to address plant safety and electrical capacity issues;
- Capital requirements from settlement agreements for the implementation of Protection, Mitigation and Enhancement (PM&E) programs related to the FERC License for the Spokane River and Clark Fork River hydroelectric projects; and

- Efficiency upgrades and improvements to meet energy and capacity requirements as determined through the Integrated Resource Plan.

Q. Please describe the capital planning process that the Generation area goes through before generation capital projects are submitted to the Capital Planning Group.

A. The capital planning process in Generation Production & Substation Support (GPSS) consists of three main phases. The first phase is a long range or 10-year plan, the second is the five-year prioritization activity, and the third is the five-year estimating process. Descriptions of each phase of the planning process follow.

The long range or 10 year plan uses a database tool that exists as the central repository for projects and their associated elements. Projects can be added to the 10-Year Database in several ways:

- Informal project requests;
- Input from asset life cycle, condition, needs assessment;
- Periodic report from Maximo of open corrective maintenance work orders;
- Periodic report from Maximo of scheduled preventive maintenance work orders;
- Annual maintenance requirements;
- Regulatory mandates;
- Project change requests- drop ins, budget changes, etc.;
- Formal project request applications; and
- Efficiency and IRP related upgrades.

The GPSS managers meet quarterly to review the 10-year plan, confirm that it is up to date and close completed projects. New projects are highlighted and noted. The impact of each additional project is reviewed. Any disagreement in the priority of projects is discussed until a solution is found.

The GPSS management team then participates in an annual workshop in preparation for the budget cycle to prioritize the projects included in the five-year horizon. The team utilizes a formal ranking matrix to insure that the projects are prioritized consistently.

Annually, the projects for the next year will be assigned and any capacity or budget constraints are identified and project schedules adjusted accordingly by the GPSS Management Team. GPSS Management and key stakeholders meet monthly at the Generation Coordination Meeting and specific Program or Project Steering Committee Meetings to discuss changes and progress to the schedule. Adjustments and consensus will take place at these meetings.

Q. What generation-related capital projects are planned to be completed in the next five years?

A. Table No. 6 shows the amount of projected generation capital transfers to plant by project and by year from 2017 through 2021on a system basis. The main investment drivers (as discussed earlier) of capital transfers for generation resources include asset condition, failed plant and operations, mandatory compliance, and performance and capacity. Details about the generation-related capital projects over the period 2017-2021 are discussed below, and business cases supporting each of these projects are provided in Exh. SJK-4.

Table No. 6: Generation Capital Spending by Business Case (2017 – 2021)

($000's)					
Business Case Name	**2017**	**2018**	**2019**	**2020**	**2021**
Traditional Pro Forma Study (Pro Forma) Projects:					
Asset Condition					
Little Falls Plant Upgrade	10,481				
End of Period Rate Base Study and Rate Year Projects:					
Asset Condition					
Automation Replacement	500	450	600	602	390
Cabinet Gorge Automation Replacement	330	$ 2,093			
Cabinet Gorge Station Service Replacement		2,137		2,138	
Cabinet Gorge Unit 1 Refurbishment	4				
Generation DC Supplied System Upgrade	1,220	1,646	750	1,698	3,484
Kettle Falls CT Control Upgrade		669			
Kettle Falls Stator Rewind	6,316				
Little Falls Install Obermeyer Gate				14,723	
Little Falls Plant Upgrade		16,444			
LL HED Emergency Generator Plant					725
Long Lake Plant Upgrades	78	3,950	5,000	250	12,600
Nine Mile Rehab	9,526	2,213	16,210		
Noxon Station Service	2,503	1,290			
Peaking Generation	500	500	500	500	500
Post Falls Redevelopment	1	4,500	7,200		53,575
Purchase Certified Rebuilt Cat D10R Dozer	814				
Replace Cabinet Gorge Gantry Crane	74	3,637			
Failed Plant and Operations					
Base Load Hydro	1,401	1,149	1,149	1,149	1,149
Base Load Thermal Plant	2,494	2,200	2,200	2,200	2,200
Regulating Hydro	6,131	3,533	3,533	3,533	3,533
Mandatory and Compliance					
Colstrip Thermal Capital	9,500	4,420	10,370	8,945	2,940
Clark Fork Settlement Agreement	7,394	6,052	39,097	4,622	10,794
Hydro Safety Minor Blanket	350	50	55	50	55
Kettle Falls RO System	4,510				
Spokane River License Implementation	2,007	2,786	533	419	613
Performance and Capacity					
Energy Imbalance Market				11,200	300
Total Planned Generation Capital Projects	**$ 66,135**	**$ 59,718**	**$ 87,196**	**$ 52,029**	**$ 92,859**

Q. Would you please explain the capital projects related to asset conditions that are planned to be completed in the next five years?

A. Yes, these capital projects include investments to replace assets based on established asset management principles and strategies adopted by the Company, which are designed to optimize the overall lifecycle value of the investment for our customers. Projects in this investment category are identified in Table No. 6 above.

Brief descriptions of each project, the reasons for the projects, the risks of not completing the projects, and the timing of the decisions follow. Additional details can be found in Exh. SJK-4 Generation and Environmental Capital Project Business Cases.

The following project is included in the Company's <u>Traditional Pro Forma Study:</u>

Little Falls Plant Upgrade - 2017: $10,481,000

This is an ongoing multi-year project to replace the Little Falls equipment that ranged in age from 60 to more than 100 years old. Forced outages at Little Falls because of equipment failures have significantly increased from about 20 hours in 2004 to several hundred hours in the past few years. This project replaces nearly all of the older, unreliable equipment with new equipment, including replacing two of the turbines, all four generators, all generator breakers, three of the four governors, all of the automatic voltage regulators, removing all four generator exciters, replacing unit controls, changing the switchyard configuration, replacing the unit protection system, and replacing and modernizing the station service. Without this focused replacement effort forced outages and emergency repairs would continue to increase, reducing the reliability of the plant. At some point, personnel may need to be placed back in the plant adding to the operating costs. The Asset Management group analyzed the age and condition of all of the equipment in the plant. All of the equipment has been qualified as obsolete in accordance with the obsolescence criteria tool. There are many items in this 100 year old facility which do not meet modern design standards, codes and expectations. This replacement effort will allow Little Falls to be operated reliably and efficiently. Upgrades and replacements associated with two of the four units at Little Falls have been completed. The replacements associated with the remaining two units will be performed over the next two to three years.

The following projects for the years 2017-2021 are included in the Company's <u>End of Period Study and Rate Year Study</u>:

Automation Replacement - 2017: $500,000; 2018: $450,000; 2019: $600,000; 2020: $602,000; 2021: $390,000

The Automation Replacement project systematically replaces the unit and station service control equipment at our generating facilities with a system compatible with Avista's current standards for reliability. Upgrading control systems within our generating facilities allows us to provide reliable energy. The Distributed Controls Systems (DCS) and Programmable Logic Controllers (PLC) are used to control and monitor Avista's individual generating units as well as each total generating facility. The DCS and PLC work is needed now to reduce the higher risk of failure due to the aging equipment. The DCSs are no longer supported and spare modules are limited. The modules in service have a high risk of failure as they are over 20 years old. The computer drivers that are needed to communicate to the DCSs will not fit in new computers with Windows 10 operating systems, creating a cyber-security issue. The software needed to view and modify the logic programs only runs on Windows 95. Avista has a very limited supply of Windows 95 laptops and they also continue to fail. Replacing aging DCSs and PLCs will reduce unexpected plant outages that require emergency repair with like equipment. A planned approach allows engineers and technicians to update logic programs more effectively and replace hardware with current standards.

Avista's hydro facilities were designed for base load operation, but are now called on to quickly change output in response to the variability of wind generation, to adjust to changing customer loads, and other regulating services needed to balance the system load requirements and assure transmission reliability. The controls necessary to respond to these new demands include speed controllers (governors), voltage controls (automatic voltage regulator a.k.a. AVR), primary unit control system (i.e. PLC), and the protective relay system. In addition to reducing unplanned outages, these systems will allow Avista to maximize ancillary services within its own assets on behalf of its customers rather than having to procure them from other providers.

Cabinet Gorge Automation Replacement - 2017: $330,000; 2018: $2,093,000

The Cabinet Gorge Automation Replacement project replaces the unit and station service control equipment with a system compatible with Avista's current standards. This plant was designed for base load operation, but is now called on to quickly change output in response to the variability of wind generation, to adjust to changing customer loads, and other regulating services needed to balance the system load requirements and assure transmission reliability. The controls necessary to respond to these new demands include speed controllers (governors), voltage controls (automatic voltage regulator a.k.a. AVR), primary unit control system (i.e. PLC), and the protective relay system. In addition to reducing unplanned outages, these systems will allow Avista to maximize ancillary services on behalf of its customers rather than having to procure such services from other providers.

Cabinet Gorge Station Service Replacement - 2018: $2,137,000; 2020: 2,138,000

The Cabinet Gorge Station Service project includes replacement of several components, many of them original to the plant. Station Service is an elaborate system required to provide electric power to the plant with multiple built-in redundancies designed to protect the plant's electrical operation. Station Service components include Transformers, Power Centers, Motor Control Centers, Load Centers, Emergency Load Centers and various breakers. The Station Service transformers no longer have the capacity to provide adequate plant load service and could be subject to overload. The current Motor Control Centers (MCC) lack monitoring and indication. Replacement of these MCCs would create operational efficiencies by providing visibility into Station Service performance. The cables require evaluation due to the age of insulation and the wet conditions they have been subject to over the years. The weight due to the number of cables in the tray is a cause of concern for potential failure. Due to system additions, the existing Emergency Generator no longer meets the load critical requirements for the plant. If no action is taken, there is a risk of individual component failure that could force load shedding under certain operational scenarios. If a catastrophic failure occurred within the switchgear and/or power cables, it could result in generator unit and/or plant wide forced outages potentially lasting as long as eight months because of the manufacturing lead time for some specialized equipment. Unplanned hydro outages can result in either purchasing higher cost replacement power from the market or utilizing other more costly Avista generation, and may result in FERC license violations if the plant needs to spill water.

Cabinet Gorge Unit 1 Refurbishment - 2017: $4,000

This is the final capital portion of a major overhaul project completed on Cabinet Gorge Unit #1. The runner hub had significant mechanical issues and needed to be replaced to allow for frequent cycling associated with the integration of intermittent renewable resources. The previous automatic voltage regulator provided a relatively slow response due to its hybrid design and had no limiters for generator protection. The new system provides faster response and adds limiters. The new machine monitoring allows for better analysis of machine condition for this important unit. Rehabilitation of this unit allows flexibility to operate under minimum river flow for fish habitat.

Generation DC Supplied System Upgrade - 2017: $1,220,000; 2018: $1,646,000; 2019: $750,000; 2020: $1,698,000; 2021: $3,484,000

The Generation DC Supplied System Upgrade is a multiyear project to update existing plant DC systems to meet Avista's current Generation Plant DC System Standard. This program will make compliance with the NERC PRC-005 Reliability Standard more tenable and significantly reduce plant outage times now required for periodic testing to meet the standard. The project changes DC System configurations to more easily comply with the NERC requirements for inspection and testing. It addresses battery room environmental conditions to optimize battery life. The project replaces legacy UPS systems with an inverter system and addresses auxiliary equipment based on its life cycle. The Company is currently addressing Battery Bank replacement based on the manufacturers recommended life cycle, which is based on ideal operating conditions. For temperatures fifteen degrees F over the normal operating temperature, the life cycle decreases 50 percent. Component failure, utilization from multiple extended outages and manufactures quality are problems we have experienced on these systems. The alternative approach of replacing components as they fail and gradually building out to Avista’s current standard may reduce program costs, but adds significant risk of unpredictable full system failures leading to forced plant outages. This program covers both thermal and hydro generation assets. Each planned project will take approximately 16 to 18 months to complete. Added complexity, cost, and time may be needed if extensive work is required to address the temperature and other environmental issues with the location of each new battery system.

Kettle Falls CT Control Upgrade - 2018: $669,000

This project will replace the Solar Combustion Turbine HMI software and hardware, upgrade PLC controls platform, and replace the Fire Protection system. The current controls are outdated, with spare parts and software support no longer available. Without this project, the system will continue to deteriorate, increasing the risk of forced outages. In 2002, KFGS added a second 7 MW generating unit at the facility that can operate in simple or combined cycle modes. Operation of this CT, the associated heat recovery steam generator (HRSG) and fire protection is done remotely through the Solar TTX controls system. The controls platform is legacy equipment and the control program is no longer supported. Additionally, the installed version of the Allen Bradley control network has not been supported for many years. The Human Machine Interface (HMI) control system used by operations functions on Windows 2000 software, which is no longer available or supported. The desktop operating computer recently failed and the plant is now operating without a spare. With this failed HMI, the HRSG cannot be operated from the local control panel at the turbine enclosure. If the remaining HMI fails, the CT will only be able to be operate in the simple cycle mode as there will not be any communication with the HRSG system. The fire protection system is no longer supported and the unit will not be operated without the fire protection system in service due to insurance requirements. The unit posted its third and fourth highest forced outage rates in the past 15 years in 2013 and 2014. The higher forced outage rate was mostly attributed to components failing within the fire protection system. The upward failure trend is expected to continue. With an increase in plant operations and increasing forced outage rate, mostly attributed to control devices failing on the fire protection system, various options were discussed. Doing nothing will eventually put the combustion turbine in an unreliable and unsafe mode. The option chosen includes installation of new software and hardware in conjunction with upgrading the fire protection system with the newest turbine controls. Completion of this project will increase unit reliability while maintaining safe operations.

Kettle Falls Stator Rewind - 2017: $6,316,000

The KFGS Stator Rewind project aims to rewind the 30 plus year old stator, which is at the end of its expected life. Field inspections performed by GE and Avista using industry standard megger tests have shown a decline in the winding insulation resistance. A 2014 report prepared by the Asset Management group demonstrated the prudency of replacing the winding before it fails in service. Failing in service would significantly extend the outage time and the cost to repair. Scheduled work to rewind the stator is a proactive measure to ensure uninterrupted and efficient operations. This project consists of monitoring the existing machine, developing a rewind contract, manufacturing replacement coils, disassembly, coil removal, new coil installation, reassembly, startup, testing and commissioning. The consequences of a stator failure include an unscheduled outage with lost generation, loss of renewable energy credits required for compliance with the Energy Independence Act, long term interruption of fuel supply, potential collateral damage to the core and hydrogen cooling, and poses a significant safety hazard.

Little Falls Install Obermeyer Gate - 2020: $14,723,000

Flashboards were added at Little Falls in the 1940's to increase the head of the plant and produce more energy. These flashboards are in three long sections and when flows exceed the capacity of the available generating units and the two tainter gates, one or more sections of the flashboard must be "pulled" or "tripped" to prevent flooding upstream. Two sections are pulled with a long wire cable strung around the flashboards and routed though makeshift pulleys to a truck with a front-end winch on the shore of the reservoir. As the winch pulls the cable, the retracting cable pulls the flashboards away from their bracing. The force of the height of the water helps the cable "rip" the flashboards from the bracing releasing the water. The Flashboards themselves are flooded downstream and are not recovered. Removal of the other section requires manual removal from a barge. Both the cable trip system and the manual method have significant safety implications to the personnel who are performing the work. Should unanticipated flows come faster than expected, or if a generating unit trips off, the reservoir level can rise quickly placing crews at risk of being taken over the face of the dam. Failure to remove all of the flashboards can cause unacceptable flooding upstream. Removing the flashboards when unnecessary costs customers by not generating as much energy as possible. A secondary issue is the annual cost to purchase and replace the flashboards that are tripped and washed downstream. In addition, both tripping the flashboards and then re-installing them after the high flows have receded requires crews to be dispatched for 10 to 14 days to re-install the flashboards. Finally, because the flashboards cannot be restored until after flows move below plant capacity to allow crews to safely work, there is a loss of head that reduces the energy from the plant. The installation of a rubber dam, flap gates, or some combination of the two are planned. Maintenance to the tainter gate structure will also be done.

Little Falls Plant Upgrade - 2018: $16,444,000

Please see the details for the Little Falls Plant Upgrade above under the Modified Historical Test Year project above.

Long Lake HED Emergency Generator Plant - 2021: $725,000

This project involves the replacement of the Long Lake Plant Emergency Generator, which serves as a back-up power source for critical unit systems if station service is lost. The 1980s era system is designed to provide power to essential systems to protect machinery and personnel in the event of a complete loss of station service power. A partial list includes power for governor oil pumps to maintain control of the turbines, sump pumps to prevent the plant from flooding, power to the battery chargers to keep the critical DC system available, and some egress lighting for personnel to safely navigate the area. The emergency generator controls are now well over 30 years old and parts are no longer available. While the controls are functional, they were designed for a multi-staff operating plan and do not provide the visibility and capability needed for the single operator operation that we run today. The technology needs to be upgraded. The complete system is made up of the Emergency Generator, controls and power leads; the Transfer Switch that connects either the normal station service or the emergency generator to the critical Load Center; and the Critical Load Center which provides the distribution network to the critical loads. Recently, the reliability of the Transfer Switch to allow the unit to synchronize to the station service is questionable. These problems lead to uncertainty about the ability for the transfer switch to cut over to the critical bus in the event of an actual loss of normal station service supply. The Transfer Switch has no spare parts and the equipment is no longer manufactured, making repair or improved reliability impossible. Doing nothing risks loss of station service and personnel safety and is not considered a viable option.

Long Lake Plant Upgrades - 2017: 78,000; 2018: $3,950,000; 2019: $5,000,000; 2020: $250,000; 2021: $12,600,000

The Long Lake Plant Upgrade is a multiyear project to replace and improve plant equipment and systems that range from 20 to more than 100 years old. The effort will begin with the project design in 2018 and expected project completion in 2024. Forced outages at the plant have increased annually from almost zero in 2011 because of equipment failures on multiple pieces of equipment. Specifically, a turbine failed in 2015 and there have been problems with servicing and sourcing parts for the failing 1990 vintage control system. This has caused O&M spending to increase in recent years with a projected upward trend. Prior upgrades to the project are reaching the end of their useful life and have placed additional stress on the plant. There are also safety issues involved with moving station service from one generator to the other that need to be addressed. This project will replace the existing major unit equipment in kind including generators, field poles, governors, exciters, and generator breakers. The generators are currently operated at their maximum temperature which stresses the life cycle of the already 50 plus-year-old windings. Inspections of other components of the generator show the stator core is “wavy”, which is a strong indication higher than expected losses are occurring in the generator. Finally, maintenance reports have identified that the field poles on the rotor have shifted from their designed position over the years. The Generator Step Up (GSU’s) transformers are over 30 years old and operating at the high end of their design temperature. The GSU’s are approaching the end of their useful life and need to be replaced proactively rather than waiting for a failure. Personnel safety is another significant driver for this. The switching procedure for moving station service from one generator to the other resulted in a lost time accident and a near miss incident in the past five years. In addition, the station service disconnects represent the greatest arc-flash potential in the company. This project will reconfigure the system to eliminate requiring personnel to perform this operation and avoid the arc-flash potential area.

Nine Mile Rehabilitation - 2017: $9,526,000; 2018: $2,213,000; 2019: $16,210,000

The Nine Mile Redevelopment is a continuing capital project to rehabilitate and modernize the four unit Nine Mile Hydro Electric Dam. The existing three MW Units 1 and 2, which were over 100 years old, were recently replaced with two new eight MW generators/turbines. The new units added 1.4 aMW of energy and 6.4 MW of capacity above the original configuration generation levels. In addition to these capacity upgrades, the Nine Mile facility has and will receive multiple other upgrades. The additional work at the plant include upgrades to Units 3 and 4 over the next several years. The Unit 3 and 4 work includes major unit overhaul of the Runners, Thrust Bearings, and Switchgear; upgrades to the Control and Protection Package including Excitation and Governors; and Rehabilitating the Intake Gates and Trash Rack. Also the sediment bypass system will be redesigned to improve sediment passage. At completion, the total powerhouse production capacity will be increased, units will experience less outages, reduced damaged from sediment, and the failing control components will be replaced. Spending began in 2012 and is expected to continue through 2019.

Noxon Station Service - 2017: $2,503,000; 2018: $1,290,000

All generation facilities require Station Service to provide electric power to the plant. Station Service components include Motor Control Centers, Load Centers, Emergency Load Centers and various breakers. Station Service is an elaborate system with multiple built-in redundancies designed to protect the plant's electrical operation. In the fall of 2013, studies in response to an electrical overcurrent coordination issue found that a majority of the Station Service components at Noxon Rapids require replacement due to electrical capacity and rating issues stemming from the added loads at the plant and the growth of the electric system in the 50 years of service. This project seeks to create a more reliable Station Service system with the replacement of multiple components in order to avoid forced outages and to modernize the electrical delivery system in the plant. Additionally, this effort will provide remote operation and monitoring capabilities, incorporate previously incomplete service expansions, support future system expansion, improve operator safety and ensure regulatory compliance. If no action is taken, there is a risk of catastrophic switch gear failure and generator unit forced outages for up to a year. Without replacement forced load shedding under certain operational scenarios could be necessary which has an impact on plant operations. Multiple alternatives were considered for this project including do nothing. The chosen alternative replaces and upgrades the equipment described above.

Peaking Generation - 2017: $500,000; 2018: $500,000; 2019: $500,000; 2020: $500,000; 2021: $500,000

The Peaking Generation program focuses on the ongoing capital maintenance expenditures required to keep Boulder Park, Rathdrum CT, and Northeast CT operating at or above their current performance levels. The program maximizes the ability of these units to start and run efficiently when requested. The reliability of these assets will decline over time, resulting in failure to start, non-compliant emissions, or inefficient operation without this type of program. It is critical that these facilities start when requested to reduce exposure to high market prices or the loss of other Company resources. The program includes initiatives to meet FERC, NERC and EPA mandated compliance requirements.

Post Falls Redevelopment - 2017: $1,000; 2018: $4,500,000; 2019: $7,200,000, 2021: $53,575,000

The Post Falls HED has been in continual operation since 1906. The generators, turbines, and governors (turbine speed controller) are original equipment and are still in service. The brick powerhouse with riveted steel superstructure remains largely the same as when it started operation. While the plant is still producing, the generating equipment, protective relaying, unit controls, and many other components of the operating equipment are mechanically and functionally failing. The turbines are estimated to be 50 percent efficient contrasted to modern 90 plus percent efficient turbines. The existing governors have had patchwork repairs due to lack of replacement parts and while they allow for unit control, they are ineffective in their response to system disturbances. Generator voltage controllers, protective relays, and unit monitoring systems all have a similar marginal functionality. The units are exhibiting signs of failure. The age of the plant and its original design presents some personnel safety issues that have evolved over time. For example, the access port for crews to access and maintain the turbine runners is too small to allow for any type of backboard or stretcher to exit the turbine area in the event of an injury. The castings used to create the turbine water case do not allow the opening to be increased without risk of permanently damaging the water case and leaking. For this reason, crews have not been able to access the turbines to maintain the runners for nearly a decade. Additionally, control modifications from the late 1940's place the primary generator breakers inside the control room presenting an unacceptable arc flash hazard to operating and maintenance personnel. While either the operation desk or the switchgear can be relocated to address this issue, this work would cost several million dollars and would not address other issues associated with the plant.

Finally, the Post Falls project has a number of critical operational requirements that support key recreational facilities, fishery, and other FERC license requirements. The Post Falls dam must provide minimum flows during summer months to support fishery habitat downstream and is also subject to restrictions on how fast the flows through the project can change in order to meet downstream flow requirements. The present plant controls marginally provide the precision needed for this control. To address water quality issues during high river flow seasons, unit and spillway controls must follow certain procedures to minimize Total Dissolved Gas creation in the river system. In addition, flows through the project impact regional recreational resources which rely on the water control at Post Falls to maintain the water levels during the summer months. Finally, there is a City Park and boat launch that are located within the immediate upstream reservoir. Safety requirements have been implemented that require all spillgates at the project to be closed before boaters are allowed to use the boat launch and recreate in the reservoir immediately upstream. Flows that would normally go through the plant need to be passed through the spillgates instead because of the unreliability of the generating units, extended maintenance outages, unit de-rates, and forced outages. This requires the boat launch opening to be delayed or in some cases closed on an emergency basis until flows subside or the generating unit can be returned to service.

In an effort to determine a prudent course of action to address the Post Falls project, a significant Assessment Study was performed to consider a number of different options that might address the issues described above. This assessment concluded that the most prudent course of action was to redevelop the site by keeping the existing powerhouse and location. A subsequent Feasibility Study evaluated different alternatives to redevelop the existing powerhouse. Options include partial replacement through a full redevelopment while retaining the existing powerhouse structure. This Feasibility Study recommended that the project be redeveloped by shutting down the plant, removing the old equipment, and replacing it with new. A cross functional group considered the results of these studies, along with significant financial analysis, to ascertain the most attractive alternative that addressed the issues. The final conclusion of all of this effort recommended a full replacement of the existing units and other powerhouse equipment and that it is more beneficial to shut down the plant during this reconstruction. The project is expected to take five years. This work will replace the existing six generating units with six new variable blade turbine generator units. Work will also include ancillary replacements and powerhouse remediation to attain a 50-year life project. In addition, the efficiency of the new generating equipment will result in an improvement in output capacity and energy. This project will result in an estimated 40 percent increase in capacity and 15 percent increase in energy and reduce future major maintenance costs.

Purchase Certified Rebuilt Cat D10R Dozer - 2017: $814,000

Kettle Falls Generation Station utilizes two D10 CAT dozers to move nearly 500,000 green tons of waste wood around the storage area year-round. Semi-trucks move wood waste from area mills to the plant where it is moved via a conveyor system. The dozers move the material from underneath the conveying system to the storage pile. If the dozers break down and material is not moved from the conveying system, trucks back up in the yard and possibly create issues on Highway 395. Maintaining the waste wood receiving equipment at the plant is critical to the plant operations. The Fuel Equipment Operators also use the dozers to move wood to be burned for the plant operations. The facility cannot operate on wood waste without the use of a dozer. The plant may operate on natural gas at 50% capacity but is then not classified as a renewable source and the REC's are lost. The generator is also less efficient and not designed to operate on natural gas for extended periods.

Normally one dozer operates while the other is in standby until the 250 hour service is needed. Typically the dozer operates 10-12 hours each day with each machine operating 2,000 hours per year. Major overhauls require shipment over 80 miles to the nearest service center in Spokane. This work is planned and scheduled around the annual maintenance outage to reduce the risk to plant availability due to the loss of the standby dozer. Data over the past 20 years show the engine on the D10R has never reached 9,000 hours of operation between failures and the transmission has never reached 10,000 hours of operation between failures. The CAT D10R dozer has over 36,000 operating hours on the machine chassis. Major components have been rebuilt and are planned on a time base maintenance schedule. Minor components in the auxiliary systems are run until failure. Discussions with the equipment manufacture service representative identified three options to consider: major rebuild of critical components, a complete certified rebuild, and purchase of new equipment. The fourth, doing nothing, was not viable as the motor had failed and the transmission will fail at some point. The recommendation is to complete a Certified Rebuild of the CAT D10R dozer. The rebuild will be completed during the schedule annual maintenance outage and will be finished two weeks prior to the plant startup. The Certified Rebuild on our existing D10R will reset the time based maintenance of the major and minor equipment. Reliability on the D10R will increase with the complete rebuild and new brakes and steering will improve safe operation.

Replace Cabinet Gorge Gantry Crane - 2017: $74,000; 2018: $3,637,000

The Cabinet Gorge Gantry Crane project involves the replacement of the original 60 plus year old gantry crane. Previous work prolonged the crane's usefulness, but the crane is currently unable to perform dependably. The gantry crane is the only means of moving the large machinery at Cabinet Gorge in and out of the plant. Its inability to function reliably impacts the work at the plant and presents a safety risk to personnel if the crane fails to control the load. There is also a risk of not being able to accomplish emergency repairs to any of the four generating units. The gantry crane is a bottle neck preventing annual maintenance work and capital improvements. Problems with the crane impacted the Cabinet Gorge Unit 1 project (2014-2016) causing delays from two days to three weeks throughout the project. This project will deliver a state-of-the-art crane capable of safely and reliably meeting plant needs. Alternatives ranging from total replacement to refurbishment were also considered. Construction will take over four months, following dismantling of the existing crane and a year-long lead time to manufacture a new crane. We anticipate construction will be completed and the project placed in service by December 31, 2018.

Q. Would you please provide details about the capital projects related to failed plant and operations, as shown in Table No. 6 above?

A. Yes, the generation capital related to failed plant and operations covers requirements to replace assets that have failed and which must be replaced in order to provide continuity and adequacy of service to our customers, such as capital repair of storm-damaged facilities. This investment driver also includes investments in natural gas and electric infrastructure that is performed by Avista's operational staff, and which is typically budgeted under the category of blankets. The projects for this investment driver include Base Load Hydro, Base Load Thermal Plant, and Regulating Hydro. Additional details can be found in Exh. SJK-4 Generation and Environmental Capital Project Business Cases.

Base Load Hydro - 2017: $1,401,000; 2018: $1,149,000; 2019: $1,149,000; 2020: $1,149,000; 2021: $1,149,000

The Base Load Hydro program covers the ongoing capital maintenance expenditures required to keep the Upper Spokane River Plants (Post Falls, Upper Falls, Monroe Street, and Nine Mile) operating within 90 percent of their current performance, as well as meeting FERC and NERC mandated compliance requirements. The historical availability for the base load hydro plants has been declining over the past decade due to deteriorating equipment and a need to replace aging equipment and systems. These plants range from 90 to 105 years old. The program focuses on ways to maintain compliance and reduce overall O&M expenses while maintaining a reasonable level of unit availability. Projects completed under this program include replacement of failed equipment and small capital upgrades to plant facilities. Most of these projects are short in duration, and many are reactionary to plant operations issues.

Base Load Thermal Plant - 2017: $2,494,000; 2018: $2,200,000; 2019: $2,200,000; 2020: $2,200,000; 2021: $2,200,000

The Base Load Thermal Plant program is an ongoing program necessary to sustain or improve the operation of base load thermal generating plants, including Coyote Springs 2, Colstrip, Kettle Falls, and Lancaster. Capital projects include replacement of items identified through asset management decisions and programs necessary to maintain reliable operations of these plants. As this asset maintenance program matures, it is expected to decrease forced outage rates and forced de-ratings of these facilities by one standard deviation less than the current average. As these plants continue to age and are called upon to ramp more frequently to meet variations associated with renewable energy integration, their operating performance begins to degrade over time resulting in increased forced outage rates, which increases exposure to the acquisition of replacement energy and capacity from the market. Having a mature asset management program for these thermal facilities helps minimize plant degradation and market exposure. The program also includes initiatives associated with regulatory mandates for air emissions and monitoring, and projects to meet NERC compliance requirements.

Regulating Hydro - 2017: $6,131,000; 2018: $3,533,000; 2019: $3,533,000; 2020: $3,533,000; 2021: $3,533,000

The Regulating Hydro program covers the capital maintenance expenditures required to keep the Long Lake, Little Falls, Noxon Rapids and Cabinet Gorge plants operating at their current performance levels. The program works to improve plant operating reliability so unit output can be optimized to serve load obligations or sold to bilateral counterparties. Work is prioritized according to equipment needs. Sustaining this asset management program is crucial as these facilities age and are ramped more frequently to meet load fluctuations associated with renewable energy integration and changing load dynamics. Additional, efforts in this program improve ancillary service capabilities from these generating assets. This includes installing blow down systems to allow for units to be on responsive stand by and able to provide spinning reserves, moving load following demands to all of these plants, voltage regulating needs, and frequency response. The program also includes some elements of hydro license compliance as related to plant operations and equipment.

Q. Would you please provide details about the mandatory and compliance capital projects, as shown in Table No. 6 above?

A. Yes, the mandatory and compliance capital investment driver typically includes projects done for compliance with laws, rules, and contract requirements that are external to the Company (e.g. State and Federal laws, Settlement Agreements, FERC, NERC, and FCC rules, and Commission Orders, etc.). Generation capital projects in this investment driver category include Colstrip Thermal Capital, Clark Fork Settlement Agreement, Kettle Falls Reverse Osmosis System, Environmental Compliance, Hydro Safety Minor Blanket and the Spokane River License Implementation. Brief descriptions of each project, the reasons for the projects, the risks of not completing the projects, and the timing of the decisions follow.

Additional details can be found in Exh. SJK-4 Generation and Environmental Capital Project Business Cases.

Colstrip Thermal Capital - 2017: $9,500,000; 2018: 4,420,000; 2019: $10,370,000; 2020: $8,945,000; 2021: $2,940,000

The Colstrip capital additions include Avista's pro rata share of ongoing capital expenditures associated with normal outage activities on Units 3 & 4 at Colstrip. Every two out of three years, there are planned outages at Colstrip with higher capital program activities. For non-outage years, the program activities are reduced. Avista votes its 15 percent share of Units 3 & 4 and its approximate 10 percent share of common facilities to approve or disapprove of the planned expenditures proposed by the plant operator on behalf of all the owners. Avista does not operate the facility nor does it prepare the annual capital budget plan. The current operator (Talen) provides the annual business plan and capital budgets to the owner group every September. The entire body of capital work performed in a calendar year at Colstrip includes a variety of projects that the operator characterizes under the following categories: Environmental Must Do, Sustenance, Regulatory, and Reliability Must Do. Avista reviews these individual projects. Some projects are reclassified to O&M if the work does not conform to our own capitalization policy. Avista does not have a "line item veto" capability for individual projects, but can present concerns during the annual September owners' meeting. Ultimately, the business plan is approved in accordance with the Ownership and Operation Agreement for Units 3 & 4 that all six companies with ownership interests are party to.

Clark Fork Settlement Agreement - 2017: $7,934,000; 2018: $6,052,000; 2019: $39,097,000; 2020: $4,622,000; 2021: $10,794,000

The Clark Fork Protection, Mitigation and Enhancement (PM&E) measures include funding for the implementation of programs done through the License issued to Avista Corporation for a period of 45 years, effective March 1, 2001, to operate and maintain the Clark Fork Project No. 2058. The License includes hundreds of specific legal requirements, many of which are reflected in License Articles 404-430. These Articles derived from a comprehensive settlement agreement between Avista and 27 other parties, including the States of Idaho and Montana, various federal agencies, five Native American tribes, and numerous Non-Governmental Organizations. Avista is required to develop, in consultation with the Management Committee, a yearly work plan and report, addressing all PM&E measures of the License. In addition, implementation of these measures is intended to address ongoing compliance with Montana and Idaho Clean Water Act requirements, the Endangered Species Act (fish passage), and state, federal and tribal water quality standards as applicable. License articles also describe our operational requirements for items such as minimum flows, ramping rates and reservoir levels, as well as dam safety and public safety requirements. More details are discussed in the hydro relicensing section of this testimony.

Hydro Safety Minor Blanket - 2017: $350,000; 2018: $50,000; 2019: $55,000; 2020: $50,000; 2021: $55,000

The Hydro Generation Minor Blanket funds periodic capital purchases and projects to ensure public safety at hydro facilities both on and off water, for FERC regulatory and license requirements. The types of projects include barriers and other safety items like lights, signs and sirens. Section 10(c) of the Federal Power Act authorizes the FERC to establish regulations requiring owners of hydro projects under its jurisdiction to operate and properly maintain such projects for the protection of life, health and property. Title 18, Part 12, Section 42 of the Code of Federal Regulations states that, "To the satisfaction of, and within a time specified by the Regional Engineer an applicant, or licensee must install, operate and maintain any signs, lights, sirens, barriers or other safety devices that may reasonably be necessary". Hydro Public Safety measures includes projects as described in the FERC publication "Guidelines for Public Safety at Hydropower Projects" and as documented in Avista's Hydro Public Safety Plans for each of its hydro facilities.

Kettle Falls Reverse Osmosis System –2017: $4,510,000

The Kettle Falls Generating Station needs a long term solution to achieve environmental permit compliance, improve the well water supply chemistry, and replace an aging demineralization system. Currently, several short term solutions have been employed with increasing and unsustainable operation costs, which includes the use of chemicals at a cost of $40,000 per month and risk associated with a deionization system. This project will design and install a new water treatment system at Kettle Falls. If this project is not completed, it could result in plant discharge permit violations.

Spokane River License Implementation - 2017: $2,007,000; 2018: $2,786,000; 2019: $533,000; 2020: $419,000; 2021: $613,000

This capital spending category covers the ongoing implementation of PM&E programs related to the FERC License for the Spokane River including Post Falls, Upper Falls, Monroe Street, Nine Mile and Long Lake. This includes items enforceable by FERC, mandatory conditioning agencies, and through settlement agreements. Additional details concerning the PM&E measures for the Spokane River license are included in the hydro relicensing section later in this testimony. This License defines how Avista shall operate the Spokane River Project and includes several hundred requirements that must be met to retain this License. Overall, the License is issued pursuant to the Federal Power Act. It embodies requirements of a wide range of other laws, including the Clean Water Act, the Endangered Species Act, and the National Historic Preservation Act, among others. These requirements are also expressed through specific license articles relating to fish, terrestrial resources, water quality, recreation, education, cultural, and aesthetic resources at the Project. In addition, the License incorporates requirements specific to a 50-year settlement agreement between Avista, the Department of Interior and the Coeur d'Alene Tribe, which includes specific funding requirements over the term of the License. Avista entered into additional two-party settlement agreements with local and state agencies, and the Spokane Tribe; these agreements also include funding commitments. The License references our requirements for land management, dam safety, public safety and monitoring requirements, which apply for the term of the License.

Q. Would you please provide details about the performance and capacity related capital project?

A. Yes, the performance and capacity generation capital investment driver includes a range of investments that address the capability of assets to meet defined performance standards, typically developed by the Company, or to maintain or enhance the performance level of assets based on a demonstrated need or financial analysis. The Energy Imbalance Market is the only generation capital project under this investment driver. Additional details can be found in Exh. SJK-4 Generation and Environmental Capital Project Business Cases.

Energy Imbalance Market - 2021: $11,200,000

The California Independent System Operator Energy Imbalance Market (EIM) is an in-hour economic based regional resource dispatch program that allows participants to lower energy costs by dispatching less expensive resources to meet load or increasing revenue through bidding excess energy into the market. The EIM dispatches the most economic resource across its market footprint based on bid prices to balance in-hour load and generation resulting in lower overall dispatch cost for participants. The EIM also lowers the amount of on-line regulation that each utility carries, which can result in additional revenue if sold into the market. Avista will continuously monitor several factors throughout this year and plans to make a formal decision on when to join the market by the end of 2017. Several northwest and other western utilities have already joined the EIM or announced they will join in the near future. This shift in market participation may impact daily market liquidity by reducing available bi-lateral trading partners. The risk of limited trading partners could drive daily market prices higher and/or cause reliability issues if energy cannot be procured during stressed conditions such as the loss of an Avista generating facility. Another driver to consider for joining the EIM is the additional integration of renewable resources in the Avista Balancing Authority. Renewable generation requires regulation and load following to back up the intermittency of the resource. There is a tipping point where Avista's existing hydro flexibility cannot supply the required load following for the amount of renewable resources integrated into the Avista Balancing Authority. The EIM provides a cost effective back stop market to balance intermittent resources. The Washington State Clean Air Rule could drive additional renewable integration to be built in our Balancing Authority. Avista continuously receives requests from smaller solar and wind resources seeking Public Utility Regulatory Policies Act contracts. Any additional renewable resource integrated in Avista's service territory will reduce hydro flexibility to follow the resource and will be a factor in the timing of Avista joining the EIM.

Avista continues to monitor the daily bi-lateral market trading and associated liquidity as well as the potential for additional renewable resource integration in our Balancing Authority. The opportunity to lower resource dispatch costs based on estimated benefits verses the costs to join the market will be evaluated in the determination of EIM participation. Avista contracted with a consultant for a benefit analysis of joining the EIM and the results should be available by September 2017. Based on other similar northwest utilities, Avista anticipates annual benefits in the $3 to 5 million range. The benefit analysis results will be used with estimated costs to create a cost/benefit analysis to help inform the decision to join the EIM. The estimated total cost to join the market is $15 million up front with $12 million associated to capital additions and $3 million expense related costs. Annual on-going expenses are estimated to be $3.0 to 3.5 million. Implementation includes new software applications, changes to existing software, generation controls and metering upgrades, contractors to assist with implementation, and internal resources including new employees to support on-going operations. Current estimates assume 30-35 Avista employees and five contractors to support project implementation over 24-30 months. Not all estimated employees will be needed full time to support project implementation. In order to support the effort long term it is estimated that 11-13 additional full time positions will be needed and some on-going positions may be filled by changing work responsibilities. Currently the California Independent System Operator only allows two additional utilities to join the EIM every year, so the earliest Avista could join is April 2021. This was determined after the Rate Period Studies were completed for this case. The Company will update these transfer to plant dates through-out the process of this case.

IV. HYDRO RELICENSING

Q. Would you please provide an update on work being done under the existing FERC operating license for the Company's Clark Fork River generation projects?

A. Yes. Avista received a new 45-year FERC operating license for its Cabinet Gorge and Noxon Rapids hydroelectric generating facilities on the Clark Fork River on March 1, 2001. The Company has continued to work with the 27 Clark Fork Settlement Agreement signatories to meet the goals, terms, and conditions of the Protection, Mitigation and Enhancement (PM&E) measures under the license. The implementation program, in coordination with the Management Committee, which oversees the collaborative effort, has resulted in the protection of approximately 89,500 acres of bull trout, wetlands, uplands, and riparian habitat. More than 44 individual stream habitat restoration projects have occurred on 24 different tributaries within our project area. Avista has collected data on over 25,000 individual Bull Trout within the project area.

The upstream fish passage program, using electrofishing, trapping and hook-and-line capture efforts, has reestablished Bull Trout connectivity between Lake Pend Oreille and the Clark Fork River tributaries upstream of Cabinet Gorge and Noxon Rapids Dams through the upstream transport of 538 adult Bull Trout, with over 160 of these radio tagged and their movements studied. Beginning in 2015, Avista has also annually implemented experimental upstream transport of 40 to 50 radio tagged adult Westslope Cutthroat Trout from below Cabinet Gorge Dam to Cabinet Gorge Reservoir. Avista has worked with the U.S. Fish and Wildlife Service to develop and test two experimental fish passage facilities. Avista, in consultation with key state and federal agencies, is currently developing designs for a permanent upstream adult fishway for Cabinet Gorge Dam and discussing the timing of, and need for, a fishway at Noxon Rapids Dam.

In 2015, the Cabinet Gorge Fishway Fish Handling and Holding Facility was completed. A permanent tributary trap on Graves Creek (an important bull trout spawning tributary) was constructed in 2012 and testing began in 2013. The permanent trap is being iteratively optimized and evaluated to determine if additional permanent tributary traps are warranted. Concurrently, the physical attributes at a site on the East Fork Bull River are being evaluated to determine if this would be a feasible location for a future permanent trap.

Recreation facility improvements have been made to over 28 sites along the reservoirs. Avista also owns and manages over 100 miles of shoreline that includes 3,700 acres of property to meet FERC required natural resource goals, while allowing for public use of these lands where appropriate.

Finally, tribal members continue to monitor known cultural and historic resources located within the project boundary to ensure that these sites are appropriately protected. They are also working to develop interpretive sites within the project.

Q. Would you please provide an update on the current status of managing total dissolved gas issues at Cabinet Gorge dam?

A. Yes. How best to deal with total dissolved gas (TDG) levels occurring during spill periods at Cabinet Gorge Dam was unresolved when the current Clark Fork license was received. The license provided time to study the actual biological impacts of dissolved gas and to subsequently develop a dissolved gas mitigation plan. Stakeholders, through the Management Committee, ultimately concluded that dissolved gas levels should be mitigated, in accordance with federal and state laws. A plan to reduce dissolved gas levels was developed with all stakeholders, including the Idaho Department of Environmental Quality. The original plan called for the modification of two existing diversion tunnels, which could redirect stream flows exceeding turbine capacity away from the spillway.

The 2006 Preliminary Design Development Report for the Cabinet Gorge Bypass Tunnels Project indicated that the preferred tunnel configuration did not meet the performance, cost and schedule criteria established in the approved Gas Supersaturation Control Plan (GSCP). This led the Gas Supersaturation Subcommittee to determine that the Cabinet Gorge Bypass Tunnels Project was not a viable alternative to meet the GSCP. The subcommittee then developed an addendum to the original GSCP to evaluate alternative approaches to the Tunnel Project.

In September 2009, the Management Committee (MC) agreed with the proposed addendum, which replaces the Tunnel Project with a series of smaller TDG reduction efforts, combined with mitigation efforts during the time design and construction of abatement solutions take place.

FERC approved the GSCP addendum in February 2010, and in April 2010 the Gas Supersaturation Subcommittee (a subcommittee of the MC) chose five TDG abatement alternatives for feasibility studies. Feasibility studies and preliminary design were completed on two of the alternatives in 2012. Final design, construction, and testing of the spillway crest modification prototype was completed in 2013. Test results indicated over all TDG performance was positive, however, additional modifications were required to address cavitation issues. Modification of the spillway crest prototype and retesting were completed in 2014. Based on this design, construction of two additional spillway crest modifications were initiated in 2015 and completed in 2016. The test results from these two spillway crests were also favorable and modification of two more spillway crests is planned for 2017. Pending results from these additional modifications, it is anticipated that up to three additional spillway crests will be modified by 2018.

Q. Would you please give a brief update on the status of the work being done under the Spokane River Hydroelectric Project's license?

A. Yes. The Company received a new 50-year license for the Spokane River Project on June 18, 2009. The License incorporated key agreements with the U.S. Department of Interior (Interior) and other key parties in Idaho and Washington. Implementation of the new license began immediately, with the development of over 40 work plans prepared, reviewed and approved, as required, by the Idaho Department of Environmental Quality, Washington Department of Ecology, Interior, and the FERC. The work plans pertain not only to license requirements, but also to meeting requirements under Clean Water Act 401 certifications by Idaho and Washington and other mandatory conditions issued by Interior.

Since 2011, Avista has implemented wetland, water quality, fisheries, cultural, recreation, erosion, aquatic weed management, aesthetic, bald eagle, operational and related conditions across all five hydro developments under the Protection Mitigation and Enhancement (PM&E) measures.

Avista worked with the Coeur d'Alene Tribe (Tribe) to purchase 656 acres of wetland mitigation properties in 2011 and 2012 along Upper Hangman Creek. These properties were purchased utilizing the Coeur d'Alene Reservation Trust Resources Restoration Fund that Avista established in 2009. Avista, in cooperation with the Tribe, has developed and implemented wetland restoration plans for 508 of the required 1,424 replacement acres of wetland and riparian habitat along Upper Hangman Creek. Avista and the Tribe continue implementing the wetland plan by assessing and pursuing additional lands, primarily on the Coeur d'Alene Reservation, for acquisition and wetland and riparian habitat restoration.

In Idaho, Avista partnered with the Idaho Department of Fish and Game (IDFG) to complete a wetland restoration project on the 124 acre Shadowy St. Joe Wetland Complex. Avista and IDFG continue to evaluate additional wetland protection and/or restoration projects in Idaho. Avista purchased the 109 acre Sacheen Springs Wetland Complex located along the Little Spokane River in Washington. The Company developed a management plan for the wetland complex, which will be protected in perpetuity under a conservation easement.

Avista also implements aquatic weed management plans in Coeur d'Alene Lake in Idaho, and Nine Mile Reservoir and Lake Spokane in Washington. The primary components of these plans include monitoring, managing, and educational outreach efforts to assist in reducing or controlling invasive and problematic weeds within the Project area.

Avista will continue to develop and implement local, state, and federally required work plans related to fisheries and water quality to fulfill License conditions. One on-going fishery study includes assessing redband trout spawning areas in the Spokane River between Monroe Street Dam and the Nine Mile Reservoir, (over a 10-year period) to determine if spring water releases from the Company's Post Falls Dam should be changed to benefit the spawning areas.

The Company completed the Long Lake Dam Spillway Modification Project, following the model and design phases, to reduce total dissolved gas (TDG) in the river downstream of the dam. The cost to construct the spillway deflectors was approximately $12.0 million. Avista will establish a spillgate protocol to determine the most effective operational scenario to reduce TDG and will monitor TDG downstream of the dam in 2017 and 2018 to determine the effectiveness in reducing TDG.

Avista completed the proposed dissolved oxygen (DO) improvement measure in the Long Lake Dam tailrace and continues to monitor its effectiveness in addressing low DO in the river below the dam. The monitoring efforts will be ongoing in nature, as the Company has to balance improved DO conditions with increases in TDG, which can be detrimental to downstream fish. Avista is also continuing to evaluate potential measures to improve DO in Lake Spokane, the reservoir created by the Long Lake Dam. Cost estimates to address DO in Lake Spokane are between $2.5 and $8.0 million. These estimates will be refined as the evaluations and studies are completed. The Company conducted a pilot test to remove carp, which cause water quality problems associated with DO throughout their life cycle, from the lake in early 2017. The pilot project was successful, allowing the Company to move forward with a more extensive carp removal effort in the Spring of 2017. Avista is also working closely with the Washington Department of Fish and Wildlife and the Washington Department of Ecology on a multi-year habitat assessment for salmonoids for Lake Spokane.

Avista partnered with the Idaho Department of Environmental Quality to complete nutrient monitoring in the northern portion of Coeur d'Alene Lake and in the Spokane River downstream of the Lake's outlet to meet the water quality monitoring requirements under the license. It also partnered with the Tribe to complete nutrient monitoring in the southern portion of Coeur d'Alene Lake and the lower St. Joe River. The Company further conducted nutrient monitoring in Lake Spokane as part of its Lake Spokane Dissolved Oxygen Water Quality Attainment Plan.

Avista and the Tribe continue to implement the Cultural Resource Management Plan on the Reservation, whereas Avista implements Historic Property Management Plans (off the Reservation) on Project lands in both Idaho and Washington. The primary measures include education and outreach, site monitoring, looting patrol, curation of materials collected, and reporting.

The Company continues to work with the various local, state, and federal agencies to manage the required recreation projects in Idaho and Washington. Last year, the Company completed the Post Falls South Channel Overlook and ADA access project, when it restored the area that was disturbed for the Post Falls South Channel Dam Gate Replacement Project in Idaho, and started the planning process for the Lake Spokane Campground expansion project, a cooperative effort with the Washington State Parks and Recreation Commission and the Washington Department of Natural Resources. Avista also constructed a new trailhead and trail to the Spokane River during the restoration effort for the Long Lake Dam Spillway Modification Project.

Q. Does this conclude your pre-filed direct testimony?

A. Yes it does.